

Wind Capacity Investments: Inefficient Drivers and Long-Term Impacts

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Abstract

A pure energy-only market has been shown, under certain conditions, to create the optimal incentives for market entry and exit. This research extends these results to the case of potential entrants with variable and non-controllable production, such as wind generators. The research shows how the stochasticity of the wind resource implies a trade-off between sites with higher capacity factors and higher covariance with prices at the efficient frontier. The analysis suggests that the Production Tax Credit (PTC), along with some capacity mechanisms, bias wind investment towards high-producing sites but with lower covariance of their variable output with market prices. Furthermore, since wind production depresses prices, this bias is linked to covariance between wind sites. Fixed-price support mechanisms like the PTC lead to market equilibriums with higher levels of wind correlation. The long-run effects of correlation in the wind investment portfolio in a theoretical market are somewhat nuanced, depending on the nature of the joint distribution of wind availability; they may be incorrectly interpreted in the usual discourse.

1 Introduction

The theory of spot market pricing is well-established, but open questions remain regarding long-run investments in electricity markets because of inflexible demand and because of market policies such as price caps. Capacity markets have attempted to fix the subsequent problems that result from suboptimal investment, but they end up returning many of the investment decisions to the central planner. Practical market design solutions are still debated in the present. Wind generation is inexorably tied to the crucial questions regarding generation expansion for two reasons. First, it represents a major source of capacity expansion in recent years, and was the dominant source of new capacity in the U.S. in 2014. Second, it raises interesting questions regarding resource adequacy because it is variable and not controllable, and thus can not typically be relied upon to satisfy peak demand.

The theory behind spot pricing of electricity was developed in the early 1980's and applied to deregulated wholesale markets in the 1990's and 2000's. In 1982, Caramanis extended the spot pricing theory to show that under certain conditions spot pricing would lead to optimal investment decisions in generating capacity [1], and others have arrived at similar conclusions [2]. The basic model of spot pricing from Caramanis's 1982 work is used here to develop a simplified version of the profit incentive for investment in traditional and renewable generation [1].

However, early literature regarding electricity generation investments makes some assumptions that do not hold up in practice. As a result, wholesale energy markets have experienced a "missing money" problem when energy revenues are not sufficient to recoup generator investment costs. In a 2005 paper, Hogan attributes much of the missing money problem to the energy-market price cap, and proposes high price caps coupled with an operating reserve demand curve as a workable design that incentivizes more efficient investment in an energy-only market design [3]. In 2006, Joskow discussed the missing money problem in

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electricity markets and suggested policy reform to improve the efficiency of spot wholesale electricity markets [4]. Joskow argues that ultimately, the source of the "missing money" problem is that spot prices do not rise high enough during scarcity hours to cover the additional investment costs of the peaking plants.

Other proposed solutions for the revenue adequacy / "missing money" problems involve call options or mandated capacity markets for maintaining reliability and resource adequacy, [5] [6]. Joskow et. al have written about design criteria for workable capacity markets as an alternative solution to the revenue adequacy problem [7] [8]. Cramton and Stoft review some of the essential problems in the resource adequacy problem, focusing in part on demand inflexibility, and evaluate the solutions discussed by several other authors [10].

Unfortunately, reliability capacity mechanisms in U.S. markets are typically flawed in practice. In particular, they often require the ISOs to make complicated regulatory decisions to govern investment. This leads to more centralized regulatory control of investment based on market questions that are difficult or impossible for policy makers to evaluate on suitable time scales. Furthermore, existing energy-only markets tend to contain low price caps and overstate the implied value of lost load (VOLL) through strict reliability standards, which contributes to the "missing money" problem and leads to an overemphasis on capacity markets as the solution, despite their inherent flaws.

Another portion of the literature focuses on the integration of wind energy in existing markets. In particular, researchers have noted that the system value of a wind investment depends heavily on when it produces electricity. For instance, Joskow finds the levelized cost of energy (one standard method for comparing energy costs amongst different generator types) for wind and solar based on the prices at the times in which they are available [11] and argues that the time sensitive approach more reasonably estimates their value.

In a recent paper, Wolak presents research on mean and standard deviation trade offs in wind project siting [12]. Wolak describes the optimal frontier between average hourly output (or revenue) and the standard deviation of hourly wind/solar output (or revenue). He show that the actual mix in California is far from the efficient frontier, and he suggests that a theoretical adjustment of capacity siting could increase the expected value of capacity factor by 40% without increasing portfolio standard deviation (SD). Furthermore, measures of non-diversifiable energy and revenue risk are calculated using actual market portfolios and risk-adjusted optimal portfolios. Wolak discusses reliability externalities in the context of renewable energy, and places some blame for the sub-optimal allocation on support mechanisms for renewable energy. However, Wolak does not describe how support mechanisms would lead to the measured suboptimal renewable investment. This research uses decision theory to help explain why rational producers might invest in a sub-optimal way given current policy support mechanisms.

Others have discussed about the impact of wind energy and renewable support schemes on power prices, for instance Sáenz de Miera et. al, [13] and Green and Vasilakos [14], but without focusing specifically on how support schemes impact the renewable investment decision.

This research examines the wind investment decision and reviews the impact of policy interventions such as price caps, capacity markets, and the Production Tax Credit (PTC) on wind investment in the broader system context. Section 2 derives a simple representation of the investment decision in wind generation. Section 3 shows how this extends to trade offs in capacity factor and price correlation, describing how the PTC might affect investment siting decisions. Section 4 links the effects of the PTC to a system-wide perspective, showing how fixed support systems can lead to higher variance of system output. Section 5 analyzes medium and long-run impacts of wind development with various levels of correlation. Section 6 addresses policy impacts and concludes.

2 Optimal Investments in Intermittent Generation

The value of any new investment in a electricity market is theoretically equal to the value that investment can earn in the spot market for electricity. For a theoretical electricity spot market, the optimal investment criteria is of the form first characterized in [1] for spot pricing. For a traditional generator j , considering a marginal investment k_j , the optimal investment criteria is given by

$$\frac{\partial I}{\partial k_j} = \mathbb{E} \left[\sum_{t=0}^T \left(\mu_{j,max}(t) \frac{\partial Y_{j,max}(t)}{\partial k_j} + \mu_{j,min}(t) \frac{\partial Y_{j,min}(t)}{\partial k_j} \right) + \frac{\partial C_j}{\partial k_j} \right] \quad (1)$$

where $\frac{\partial I}{\partial k_j}$ is the marginal capital cost of new investment, t refers to a single settlement period in the market, and T refers to the investment lifetime. Furthermore, $\frac{\partial Y_{j,min}(t)}{\partial k_j}$ and $\frac{\partial Y_{j,max}(t)}{\partial k_j}$ refer to the marginal change in the minimum and maximum generation capacity constraints of the generator, and $-\mu_{j,min}(t)$ and $-\mu_{j,max}(t)$ are the optimal values of the Lagrange multipliers for the generator min and max availability constraints in the optimal pricing problem. The final term, $\frac{\partial C_j}{\partial k_j}$ refers to the change in variable costs due to investment, for instance through an improvement in heat-rate or reduced variable maintenance costs.

This exposition focuses only on questions of generation expansion. Therefore, assume $\frac{\partial Y_{j,min}(t)}{\partial k_j} = 0$ and $\frac{\partial C_j}{\partial k_j} = 0$. Then, the marginal benefits of additional investment are simply the benefits from pushing out the maximum production constraint in the spot market optimization problem. Using complementary slackness, Caramanis shows that in periods t when the maximum production constraint is binding for generator j ,

$$\mu_{j,max}(t) = \pi_j(t) - \frac{\partial C_j}{\partial Y_j(t)} > 0 \quad (2)$$

where $\frac{\partial C_j}{\partial Y_j(t)}$ is generator j 's marginal cost (MC) of production and $\pi_j(t)$ is the market price seen by generator j in period t . In the competitive market, the clearing price is the same for all generators $\pi_j(t) = \pi(t) \forall j, t$.

Finally, assume that if the maximum production constraint for generator j is binding in period t , it would still be binding despite a marginal constraint improvement due to investment k_j . This allows for a reinterpretation of a simplified 1 and 2 as follows:

$$\frac{\partial I}{\partial k_j} = \mathbb{E} \left[\sum_{t=0}^T \left(\frac{\partial Y_{j,max}(t)}{\partial k_j} \max\{\pi(t) - \frac{\partial C_j}{\partial Y_j(t)}, 0\} \right) \right] \quad (3)$$

Equation 3 states a simple relationship regarding the marginal investment decisions of generators. In equilibrium, the marginal cost of a capacity investment decision should be the marginal benefit of that investment in expectation, where the total marginal benefit is the sum of the marginal benefits over all periods. In the case of efficient economic dispatch, than in any period t , the marginal benefit of the additional capacity is the amount of that capacity that is available for production, times the difference between the spot price and the generator's marginal cost, when that value is greater than 0. If the generator's marginal cost is greater than or equal to the spot price in any period t , the marginal benefit of extra investment in that period is 0.

Traditional generators usually operate with high reliability, so the value $\frac{\partial Y_{j,max}(t)}{\partial k_j}$ may be close to 1 for all periods t . Moreover, the operator of a mid-range or peaking plant can carefully plan upgrades and reliability maintenance for the shoulder season when average demand is low, so that as much capacity as possible is available in all periods when the maximum output constraint is binding. Thus, while the expected value of $\frac{\partial Y_{j,max}(t)}{\partial k_j}$ and its variation in t are important to the investor, they may not have a major differentiating impact between traditional generation investments.

On the other hand, the availability of additional generation capacity due to the investment is very important for valuing the investment in intermittent generation, like wind. In the case of wind and solar generation, the marginal cost is approximately 0, since there are no fuel costs. Correspondingly, if k_j represents investment in renewable generation, then $\frac{\partial C_j}{\partial Y_j(t)} = 0 \forall t$. To align the notation with existing work on wind generation, let

$$\frac{\partial Y_{j,max}(t)}{\partial k_j} = f_k(t) \frac{\partial W_j}{\partial k_j} \quad (4)$$

where $f_k(t)$ is the capacity availability of the new investment in time t and $\frac{\partial W_j}{\partial k_j}$ is the incremental capacity addition due to investment k_j . To simplify the analysis, normalize $\frac{\partial W_j}{\partial k_j} = 1$ so all investments have the same cost per unit of capacity. Note that the capacity availability $f_k(t)$ is a random variable whose probability distribution varies in t , as is $\pi(t)$. Therefore, the capacity factor of the new wind investment is $\mathbb{E}[\frac{1}{T} \sum_{t=0}^T f_k(t)]$. Then, the spot pricing model leads to the intuitive investment value for a wind project:

$$\frac{\partial I}{\partial k_j} = \mathbb{E} \left[\sum_{t=0}^T \left(f_k(t) \pi(t) \right) \right] \quad (5)$$

It is possible to rewrite 5 in terms of the marginal distributions of the random variables f_k and π , which have marginal distributions equally weighting all possible future values of t . For example, pick f_k so that the distribution of $f_k\pi$ conditioned on $t = t'$ is equal to the distribution of $f_k(t')\pi(t')$ for all $t' \in \{1, \dots, T\}$, and likewise for each of the marginals. Define a random variable $S \sim U(\{1, 2, \dots, T\})$. Then,

$$\begin{aligned}
\frac{\partial I}{\partial k_j} &= \mathbb{E} \left[\sum_{t=0}^T \left(f_k(t)\pi(t) \right) \right] \\
&= T \mathbb{E} \left[\sum_{t=0}^T f_k(t)\pi(t) \frac{1}{T} \right] \\
&= T \mathbb{E}_S \left[\mathbb{E}_{f_k, \pi} [f_k\pi | S] \right] \\
&= T \mathbb{E}_{f_k, \pi} [f_k\pi]
\end{aligned} \tag{6}$$

The equation in 6, the marginal investment condition for wind generation, can be interpreted as follows: the marginal value for each unit of investment in wind generation equals the investment horizon times the joint expectation of the product of the random variables for the price of electricity and the capacity availability of the new generation investment.

3 Capacity Factor and Price Correlation Trade offs in Wind Siting Decisions

The marginal investment results for an intermittent generator in the previous section are well understood, but the form suggests interesting effects on wind generation siting decisions that are not frequently discussed. In particular, there is a natural trade-off at the margin between capacity factor and covariance between energy production and electricity price, as suggested by equation 5, which is expanded here using the definition of covariance:

$$\frac{\partial I}{\partial k_j} = T \mathbb{E}[f_k\pi] = T(\mathbb{E}[f_k]\mathbb{E}[\pi] + \text{Cov}(f_k, \pi)) \tag{7}$$

Next, consider marginal investments k_j and k'_j , with $\frac{\partial I}{\partial k_j} = \frac{\partial I}{\partial k'_j}$. For simplicity, assume the two investments have the same time-horizon and involve the same marginal capacity addition. Then

$$\mathbb{E}[f_k]\mathbb{E}[\pi] + \text{Cov}(f_k, \pi) = \mathbb{E}[f_{k'}]\mathbb{E}[\pi] + \text{Cov}(f_{k'}, \pi) = \varphi \tag{8}$$

for some constant φ . By rewriting as a difference of two equal terms, observe that:

$$\mathbb{E}[\pi] + \frac{\text{Cov}(f_k, \pi) - \text{Cov}(f_{k'}, \pi)}{\mathbb{E}[f_k] - \mathbb{E}[f_{k'}]} = 0 \tag{9}$$

By considering the marginal differences between the investments and taking the limit as these differences become increasingly small, we can characterize the slope of the efficient frontier:

$$\frac{\partial \text{Cov}(f_k, \pi)}{\partial \mathbb{E}[f_k]} = -\mathbb{E}[\pi] \tag{10}$$

This suggests that a incremental decrease in the capacity factor of a potential new investment would need to be coupled with a incremental increase of $\mathbb{E}[\pi]$ units of covariance to remain on the efficient frontier.

The wind investment data from Wolak's 2015 paper [12] allows for additional insight by plotting the efficient frontier of capacity factor and correlation with prices based on real-world investment data. Wolak provides metrics for plant output and price coefficient of variation and for correlation between energy output and price, but does not include the plant capacity factors in the results. Using covariance for each plant's output with price and the average wholesale price in California, Figure 1 displays the required capacity factor any given plant would need to achieve in order to be on the efficient frontier, in accordance with equation

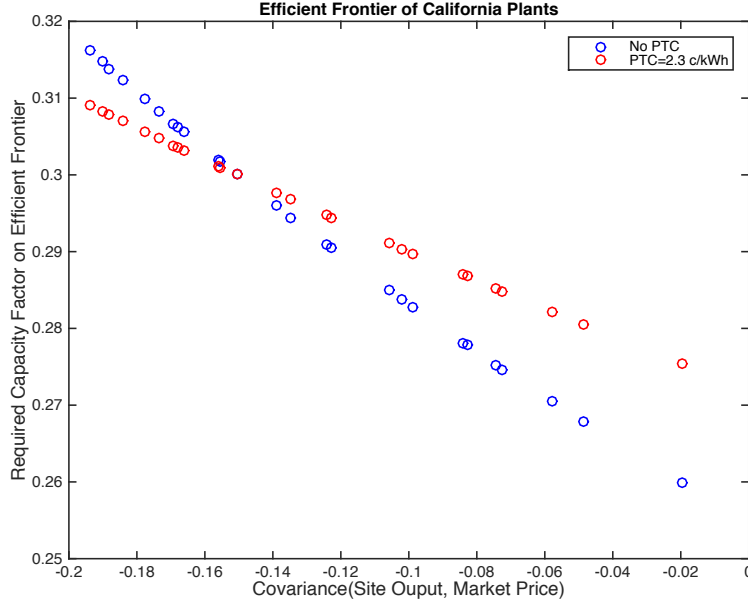


Figure 1: Theoretical Capacity Factors along Efficient Frontier for California Wind Projects with and without the PTC

10 for the ‘No PTC’ case. For comparison purposes, a single arbitrary plant is fixed as a “swing” plant with a set capacity factor $\mathbb{E}[f_k] = 0.30$. The analysis assumes that all sites experienced equivalent average prices and had equivalent marginal investment costs per unit of capacity. Note that some of the plants would be inefficient investments in the real-world, and would be below the efficient frontier. However, by using real-world data for the covariance (from [12]) to simulate the efficient frontier, the data gives a sense of the level of variation in capacity factor (a range of around 6%) one could expect from real-world plants that represent efficient investment decisions.

3.1 The Effect of the PTC on Investment Behavior

The Production Tax Credit (PTC) has been used since 1992 to stimulate investment in some renewable energy technologies, including wind. It was most recently renewed in December 2015 and extended through 2019. As of 2016, the PTC for wind is \$ 0.023/kWh, but it will begin to decline in 2017.

The PTC, a fixed-rate subsidy for wind energy, affects marginal decisions along the investment frontier, resulting in a different characterization of the frontier versus the no-subsidy case described by 10. Starting from 8, for all investments k_j, k'_j along the investment frontier

$$\mathbb{E}[f_k]\mathbb{E}[\pi] + \mathbb{E}[f_k]\phi_{PTC} + \text{Cov}(f_k, \pi) = \mathbb{E}[f_{k'}]\mathbb{E}[\pi] + \mathbb{E}[f_{k'}]\phi_{PTC} + \text{Cov}(f_{k'}, \pi) = \varphi \quad (11)$$

for some constant φ , with a fixed PTC ϕ_{PTC} . Now, following the same derivation in 10, observe:

$$\frac{\partial \text{Cov}(f_k, \pi)}{\partial \mathbb{E}[f_k]} = -\mathbb{E}[\pi] - \phi_{PTC} \quad (12)$$

When the production tax credit is considered, the efficient frontier exhibits a much steeper slope in trading off the relationship to high prices and the capacity factor of a potential site. This serves to bias investment towards sites with proportionally higher expected capacity factors, but with proportionally lower covariance of output and price.

It is important to consider how the PTC affects this bias, but it is hard to estimate from available data. As a preliminary test, we again use the data provided by Wolack to examine the effect of the PTC in biasing the efficient investment frontier. The same swing plant is fixed; assume that it is located along the efficient frontier with a fixed $\mathbb{E}[f_k] = 0.30$. The average electricity price is assumed to be the average traded price

at the Northern California NP-15 hub over all of 2015, so $\mathbb{E}[\pi] = 0.03705$, based on data from the EIA. Figure 1 provides a comparison of the efficient frontier with and without the PTC. Clearly, the PTC biases investments with higher capacity value at the expense of an improvement in covariance with price. When a fixed feed-in subsidy (the PTC) is provided to wind generators, investments will be made that are well below the true efficient frontier, at the expense of investments with higher value in the efficient market. Notably, if the subsidy was provided as a multiplier of the wholesale price of electricity in each period in which the generator was producing, the subsidy would no longer bias investment towards high capacity factors at the expense of improved production-price covariance.

In the aforementioned paper, Wolak states that the fixed-price Feed-in-Tariffs (FIT) that currently finance most wind projects could be the cause of suboptimal investment [12]. While Feed-in-Tariffs are only present in some states, they represent the most extreme form of the above analysis, one in which the effective average market price seen by the assets $\mathbb{E}[\pi] = 0$ and the fixed tariff ϕ is the FIT rate. For states where utilities are required to offer a fixed-rate FIT, like California and Maine, the resulting investment frontier would be shown as a horizontal line on the graph in Figure 1. In that extreme case, the capacity factor dominates the investment decision.

3.2 The Effect of Capacity Markets on Investment Behavior

In some markets, wind assets are allowed to participate in forward capacity markets, based on a capacity value that is determined by the regulator. For instance, in ISO-NE, the capacity value is separated by the summer and winter seasons and calculated based on the 5 year rolling average of medium net generation in those hours in the relevant season (e.g. 1-6 pm in summer months June-September). In NYISO, new onshore resources receive a 10% default capacity credit for summer capacity and a 30% default capacity credit for winter capacity, while in PJM, new wind projects received a 13% default capacity credit [16], prior to changes in the PJM Capacity Market in 2015.

The capacity allowance can be factored in to the above equations similarly to ϕ_{PTC} , as an additional rate based on the administratively determined capacity value and the capacity auction clearing price. Depending on the form of the capacity allowance, this could actually serve to bias the investment frontier in any direction. For instance, the capacity value mechanisms in NYISO [16] provide a fixed credit based on capacity, which does not take into account the actual performance of the resource at all. This is inefficient, because it would bias outcomes towards investments with relatively lower marginal costs for capacity expansion but lower average value of the energy produced and/or lower average capacity factor. PJM's new Capacity Performance Model, approved by FERC in June 2015 [17], is a step in the right direction because it has more stringent penalties for non-performance, which, if implemented correctly could lead to correct valuations of the time-sensitive nature of the wind capacity. However, some have argued that the associated penalties still do not sufficiently penalize non-compliance, so this improved capacity metric still most likely undervalues covariance between capacity availability and price versus the efficient market.

3.3 The Effect of Price Caps

The same analysis also suggests that price caps in energy-only markets might have an impact the marginal wind investments as analyzed in the previous subsections, but ultimately neither the magnitude nor the direction of the impact can be explained by the methods used here. We hypothesized that a price cap would uniformly reduce the expected benefits from a site with marginally better covariance between production and energy prices, and therefore bias investments away from the efficient frontier and towards increasing emphasis on capacity factor, as was the case with the PTC. However, because of the linear nature of covariance, it is easy to come up with examples (if improbable) where this is not the case. For instance, consider two marginal investments k_j and k'_j along the investment frontier. Assume that they have to equal mean capacity factors, but that investment k_j is ultimately more attractive because $\text{Cov}(f_k, \pi) > \text{Cov}(f_{k'}, \pi)$. Furthermore, assume that this improvement in covariance is driven by the fact that

$$\mathbb{E}[f_k | \pi = \hat{\pi}] > \mathbb{E}[f_{k'} | \pi = \hat{\pi}] \quad \forall \hat{\pi} \in [\mathbb{E}[\pi], \bar{\pi}] \quad (13)$$

and that the improvement holds true even though investment k_j is less attractive in periods of really high prices (i.e. high demand), i.e. even though

$$\mathbb{E}[f_k|\pi = \hat{\pi}] < \mathbb{E}[f_{k'}|\pi = \hat{\pi}] \quad \forall \hat{\pi} \in [\bar{\pi}, \infty] \quad (14)$$

Next, consider a parallel market but with a price cap at $\bar{\pi}$. It's easy to see that the gap in value between these investments is actually increased as a result of the price cap. Thus, a price cap, in some cases, can actually bias marginal investment in the direction of investments that were already more attractive. That said, the way that this works is still by undervaluing the impact of the wind generation in periods that are constrained by the price cap, so a price cap still ultimately provides an inefficient incentive that can affect the wind investment decision.

In general, a price cap is inefficient in that it prevents available energy from realizing a price that is actually commensurate with demand. However, even though we expect that a price cap might generally bias investment towards projects that have lower covariance with demand, this is not always the case. The effect of a price cap on individual investments depends on the details of the joint distribution of the site's wind availability and of demand, and is subject to a high-degree of uncertainty.

3.4 Policy Improvement: Proportional PTC

As explained previously, the current form of the Production Tax Credit (PTC) for wind producers clearly biases investment. This section argues that a different subsidy, provided as a multiplier of the wholesale price for electricity, would eliminate the bias present in the current form of the PTC. Here, we expand and provide evidence for that assertion.

Consider the expanded investment criterion in equation 7, but where the price received for electricity in a single time period is no longer π but rather $\lambda\pi$, for some $\lambda > 1$, where the exact value of λ can be set by policy-makers. For instance, λ could be set to achieve modeled cost equivalence with the existing PTC level ϕ_{PTC} . Under this alternative subsidy model, the investment value is given by the following:

$$\frac{\partial I}{\partial k_j} = T\mathbb{E}[f_k\lambda\pi] = T(\mathbb{E}[f_k]\mathbb{E}[\lambda\pi] + \text{Cov}(f_k, \lambda\pi)) \quad (15)$$

As before, it is possible to characterize the marginal investments along the investment frontier, for investments with the same time-horizon and involving the same marginal capacity addition:

$$\mathbb{E}[f_k]\mathbb{E}[\lambda\pi] + \text{Cov}(f_k, \lambda\pi) = \mathbb{E}[f_{k'}]\mathbb{E}[\lambda\pi] + \text{Cov}(f_{k'}, \lambda\pi) = \varphi \quad (16)$$

for some constant φ . Rewriting 16 as a difference gives that:

$$\lambda\mathbb{E}[\pi](\mathbb{E}[f_k] - \mathbb{E}[f_{k'}]) + \lambda\text{Cov}(f_k, \pi) - \lambda\text{Cov}(f_{k'}, \pi) = 0. \quad (17)$$

The properties of expectation and covariance allow us to move the constant λ outside of those terms. Dividing both terms by the difference in capacity factors, gives

$$\mathbb{E}[\pi] + \frac{\lambda(\text{Cov}(f_k, \pi) - \text{Cov}(f_{k'}, \pi))}{\lambda(\mathbb{E}[f_k] - \mathbb{E}[f_{k'}])} = 0. \quad (18)$$

where the λ terms cancel. Then, taking the limits as marginal differences become increasingly small, we characterize the investment frontier according to

$$\frac{\partial \text{Cov}(f_k, \pi)}{\partial \mathbb{E}[f_k]} = -\mathbb{E}[\pi] \quad (19)$$

which is equivalent to the original condition in 10. Therefore, a subsidy distributed proportionally to the real-time price of electricity eliminates the investment bias towards higher capacity factor sites, pushing investment towards sites the produce more valuable electricity.

In theory, the variable λ could be chosen to that the total expected profit for producers would be equal to that under the current PTC regime, i.e.

$$T\mathbb{E}[\lambda f_k \pi] = T\mathbb{E}[f_k \pi + \phi_{PTC}] \quad (20)$$

for the average or marginal producer. Then, the expected costs of the program are equivalent in either case:

$$T\mathbb{E}[(\lambda - 1)f_k\pi] = T\mathbb{E}[\phi_{PTC}] \quad (21)$$

However, the utility function of total profits is not necessarily linear for any potential investor. When considering the natural concavity of producer utility or additional aversion to risk, it becomes clear that increased incentive costs are required to maintain the same level of investment. Consider a specific potential investor m who weights profits by an increasing, concave utility function $u_m(\cdot)$, with $u(0) = 0$. Assume that under the PTC regime, the expected utility for this investor exactly equals their reservation price, i.e. they are investing at the margin. Therefore, for the producer to move ahead with an equivalent investment under the proportional price regime, their expected utility must equal or exceed that under the PTC:

$$T\mathbb{E}[u_m(\lambda f_m\pi)] \geq T\mathbb{E}[u_m(f_m\pi + \phi_{PTC})] \quad (22)$$

Proposition 1. Consider a marginal producer with strictly concave and non-decreasing utility of profit, with $u(0) = 0$. In order for this producer to invest under the proportional PTC, i.e. for the condition in 22 to hold, the expected incentive / subsidy to that investor in the proportional incentive regime must exceed that under the PTC:

$$T\mathbb{E}[(\lambda - 1)f_m\pi] > T\mathbb{E}[\phi_{PTC}f_m] \quad (23)$$

Proof. By rearranging the marginal investment requirement in 22, using the linearity of expectation, observe that:

$$\begin{aligned} 0 &\leq T\mathbb{E}[u_m(\lambda f_m\pi) - u_m(f_m\pi + \phi_{PTC}f_m)] \\ &< T\mathbb{E}[u_m(\lambda f_m\pi - (f_m\pi + \phi_{PTC}f_m))] \\ &\leq Tu_m(\mathbb{E}[\lambda f_m\pi - (f_m\pi + \phi_{PTC}f_m)]) \end{aligned} \quad (24)$$

The second inequality is due to the strict concavity of $u_m(\cdot)$, since $u(a + b) \leq u(a) + u(b)$ implies that $u(c) \leq u(a) + u(c - a)$ and therefore $u(c) - u(c - a) \leq u(a)$, as above. It holds strictly if $u_m(\cdot)$ is strictly concave. The third inequality is true by Jensen's inequality.

Since $u_m(0) = 0$ and $u_m(\cdot)$ non-decreasing, $u(x) > 0 \rightarrow x > 0$. From the inequalities in 24, it is therefore true that

$$T\mathbb{E}[\lambda f_m\pi - (f_m\pi + \phi_{PTC}f_m)] > 0 \quad (25)$$

By rearranging terms and using the linearity of expectation, it is clear that this is equivalent to 23 above. \square

In practice, wind investors may exhibit concave utility curves or general aversion to risk. For this more general class of producers with concave utility curves, it is more expensive on average to subsidize the marginal investment (and thus, to subsidize the same amount of total investment, given equal opportunities) under a price-based proportional incentive versus the traditional PTC. There are two main benefits, however, to the proportional incentive. First, the proportional incentive regime leads to increased average value for wind energy production, as argued in this section. Second the proportional incentive regime leads to lower variance of total wind output, as Section 4 will argue. A higher total output variance increases potential grid security costs, which are hard to price in electricity markets, and it can increase the difficulty of decarbonizing the electricity sector. The additional costs of the proportional incentive must be seen as a trade-off and evaluated versus the benefits described here.

Besides costs, there are some additional considerations required of any subsidy comparison. One goal of subsidies, like the Production Tax Credit, is to provide support to a nascent industry. The nominal goal of either incentive type, either increasing wind generation or increasing total wind energy value created, is a reasonable framing of that intent.

On the other hand, subsidies for wind energy are also used to help reduce greenhouse gas emissions in the electricity sector. For this goal, the existing PTC might seem a more efficient fit, since it provides an incentive to wind energy based on total kWh of energy produced (and thus roughly based on kWh of fossil fuels provided). In fact, if a PTC encourages wind producers to bid below their marginal cost of production, for instance to bid $\frac{\partial C_j}{\partial Y_j(t)} - \phi_{PTC}$, then the producers will essentially only receive the value of the credit (vs.

the counter-factual where there is no credit and wind producers bid their MC) in the cases where wind is displacing some fossil fuel energy.

However, the traditional PTC also serves as an inefficient incentive for greenhouse gas reduction because it does not take into account variation in emissions from different sources. In a system where marginal production is frequently a single type of generator, but with varying levels of efficiency and therefore cost (for instance, California or New York with natural gas), the proportional PTC might actually be more reflective of the level of marginal emissions reductions.

4 Output-Price Covariance and Variance of Total System Wind Output

The fixed-rate subsidy analyzed in this section is clearly inefficient in the sense that they bias wind investment away from the socially optimal portfolio. These regulatory failures may help explain the under performance of existing wind assets versus an efficient portfolio, as evidenced by Wolak for wind and solar generators in California [12].

Besides covariance with price, variance of total system output is an important metric for the efficiency of any group of wind investments. High variance of total system output is equivalent to higher intermittency [12], which is associated with higher price swings, lower system stability, and greater challenges for integrating renewable resources. From the perspective of a single producer k , define residual wind output as the random variable sum of capacity availability of all other producers $S_{-k} \stackrel{def}{=} \sum_{i \neq k} f_i$. This section develops theoretical results to link the covariance of a particular producer with price $\text{Cov}(f_k, \pi)$ with covariance of a particular producer with remaining system production $\text{Cov}(f_k, S_{-k})$ and total system wind output variance $\text{Var}(f_k + S_{-k})$ for any k . This allows us to extend the previous results to predict that policies like the PTC will lead to increased system wind variance as compared to investments in the unsubsidized or proportionally subsidized case.

The key fact that connects these results is that wholesale energy market prices are decreasing in wind output. Energy production from wind generators has 0 or near-0 marginal costs, and thus it nearly always clears in any auctions when it is available. Therefore, wind production reduces thermal generation demand and lowers the clearing price for electricity. Since the supply curve is increasing, then price is necessarily a decreasing function of wind output. The magnitude of this effect depends on electricity demand during the current period - if the demand curve shifts during periods of already low demand, the supply curve may be relatively flat in the base-load region and the price suppression may be small. However, the direction is clear - in any given period, increased wind production decreases electricity clearing prices. As such, it is useful to model price as a decreasing function of available wind generation, i.e. $\pi = g(S_{-k})$ with $g(\cdot)$ strictly decreasing. The price earned by potential new investment k at any given time is strictly decreasing in the output of all other wind producers.

Therefore, for any given wind investment, covariance with energy price is directly influenced by the covariance between its output and that of other wind generators. The following proposition makes this clear:

Proposition 2. Consider two wind power sites whose availability is characterized by random variables f_k and f'_k , satisfying $\mathbb{E}[f_k] = \mathbb{E}[f'_k]$. Assume that the conditional expectation functions of f_k and f'_k with respect to the residual wind outputs S_{-k} are single crossing. Assume further that price is a strictly decreasing function of residual output S_{-k} . Then, a higher output covariance with respect to price is equivalent to a lower output covariance with respect to residual wind output. That is,

$$\text{Cov}(f_k, \pi) < \text{Cov}(f'_k, \pi) \iff \text{Cov}(f_k, S_{-k}) > \text{Cov}(f'_k, S_{-k}) \quad (26)$$

Proof. Fix random variables f_k and f'_k such that $\mathbb{E}[f_k] = \mathbb{E}[f'_k]$ and that conditional expectations $\mathbb{E}[f_k|S_{-k}]$ and $\mathbb{E}[f'_k|S_{-k}]$ are single crossing. That is, $\exists y$ such that either

$$\begin{aligned} \forall x \geq y \mathbb{E}[f_k|S_{-k} = x] \geq \mathbb{E}[f'_k|S_{-k} = x] \text{ and } \forall x \leq y \mathbb{E}[f_k|S_{-k} = x] \leq \mathbb{E}[f'_k|S_{-k} = x] \\ \text{or } \forall x \geq y \mathbb{E}[f_k|S_{-k} = x] \leq \mathbb{E}[f'_k|S_{-k} = x] \text{ and } \forall x \leq y \mathbb{E}[f_k|S_{-k} = x] \geq \mathbb{E}[f'_k|S_{-k} = x] \end{aligned} \quad (27)$$

Note that no assumption is made about the direction of the single crossing property. Furthermore, the random variables f_k and f'_k might have very different joint probability distributions with the existing wind

availability S_{-k} . This single crossing property is satisfied by many types of joint distributions. For instance, if both (f_k, S_{-k}) and (f'_k, S_{-k}) are bivariate normal, then the functions $\mathbb{E}[f_k|S_{-k} = x]$ and $\mathbb{E}[f'_k|S_{-k} = x]$ are linear and are single crossing at the point $y = \mathbb{E}[S_{-k}]$.

First, the proof will establish that the first condition of 26 implies the second. The proof of the converse follows the same logic. Assume $\text{Cov}(f_k, \pi) < \text{Cov}(f'_k, \pi)$. Then

$$\begin{aligned} 0 &> \text{Cov}(f_k, \pi) - \text{Cov}(f'_k, \pi) \\ &= \mathbb{E}[f_k \pi] - \mathbb{E}f_k \mathbb{E}\pi - \mathbb{E}[f'_k \pi] + \mathbb{E}f'_k \mathbb{E}\pi \\ &= \mathbb{E}[(f_k - f'_k)g(S_{-k})] \end{aligned} \tag{28}$$

where the final equality is due to linearity of expectation, $\mathbb{E}[f_k] = \mathbb{E}[f'_k]$, and by rewriting price as a decreasing function of the random variable S_{-k} .

Due to the single crossing property, assume $\exists s_0$ that is the crossing-point separator that satisfies the conditions in 27. Assume that the random variable S_{-k} has support on some range that includes s_0 in its interior, i.e. there is a set $A = \{x \in \mathbb{R} | 0 < \mathbb{P}(S_{-k} \leq x) < 1\}$ and $s_0 \in \text{int}(A)$.

Note that since $\mathbb{E}[f_k] = \mathbb{E}[f'_k]$ and $g(s_0)$ is just a constant, $\mathbb{E}[(f_k - f'_k)g(s_0)] = 0$. Subtracting this from both sides of the equation 29 implies that

$$\begin{aligned} 0 &> \mathbb{E}[(f_k - f'_k)(g(S_{-k}) - g(s_0))] \\ &= \mathbb{E}[(\mathbb{E}[f_k|S_{-k}] - \mathbb{E}[f'_k|S_{-k}])(g(S_{-k}) - g(s_0))] \end{aligned} \tag{29}$$

where the equality is due to the law of total expectation. But this requires that the single crossing property is governed by the first line of 27. If it were not, then the second line must hold true and $\forall S_{-k} = s < s_0$, $\mathbb{E}[f_k|S_{-k}] \geq \mathbb{E}[f'_k|S_{-k}]$ by the single crossing property and $g(S_{-k}) > g(s_0)$ since $g(\cdot)$ decreasing. Similarly, $\forall S_{-k} = s \geq s_0$, $\mathbb{E}[f_k|S_{-k}] \leq \mathbb{E}[f'_k|S_{-k}]$ by the single crossing property and $g(S_{-k}) \leq g(s_0)$. But combined, these statements imply that $(\mathbb{E}[f_k|S_{-k}] - \mathbb{E}[f'_k|S_{-k}])(g(S_{-k}) - g(s_0)) \geq 0$ almost surely. This implies that $\mathbb{E}[(\mathbb{E}[f_k|S_{-k}] - \mathbb{E}[f'_k|S_{-k}])(g(S_{-k}) - g(s_0))] \geq 0$, which is a contradiction with (29). Therefore, the second line of 27 can not be true, so the first must be. But then, $(\mathbb{E}[f_k|S_{-k}] - \mathbb{E}[f'_k|S_{-k}])(S_{-k} - s_0) > 0$ almost surely, which implies:

$$\begin{aligned} 0 &< \mathbb{E}[(\mathbb{E}[f_k|S_{-k}] - \mathbb{E}[f'_k|S_{-k}])(S_{-k} - s_0)] \\ &= \mathbb{E}[(f_k - f'_k)(S_{-k} - s_0)] \\ &= \mathbb{E}[(f_k S_{-k}] - \mathbb{E}[(f'_k S_{-k}] \\ &= \mathbb{E}[(f_k S_{-k}] + \mathbb{E}f_k \mathbb{E}S_{-k} - \mathbb{E}[(f'_k S_{-k}] - \mathbb{E}f'_k \mathbb{E}S_{-k} \\ &= \text{Cov}(f_k, S_{-k}) - \text{Cov}(f'_k, S_{-k}) \end{aligned} \tag{30}$$

The first and third equality use the fact that $\mathbb{E}[f_k] = \mathbb{E}[f'_k]$, and the final equality uses the definition of covariance. Therefore, the proof and the final line of (30) shows that $\text{Cov}(f_k, \pi) < \text{Cov}(f'_k, \pi)$ implies $\text{Cov}(f_k, S_{-k}) > \text{Cov}(f'_k, S_{-k})$. The proof of the converse follows in the same way, but replacing the inequalities with their converse. This establishes the equivalence of the two statements in 26. \square

Remark 1. While Proposition 2 proven in the case where the conditional expectations are single crossing, the single crossing property is not a requirement for the result in any specific case. Roughly, if the conditional expectations of the outputs of two potential sites with respect to total system wind output are ‘nearly’ single crossing, then the result will hold. For instance, for a specific pair of sites, if the conditional expectations are about equal over some range, or have a second ‘crossing’ conditioned on some set with sufficiently small measure, then for these sites it will remain true that the ranking of each of their covariances with price will be equivalent to the ranking of their covariance with system output.

Based on these results, the covariance between price and a single plant’s output can be thought of as a variable partially determined by two separate factors, the covariance between that plant’s output and the load demand, and the covariance between that plant’s output and the output of other wind generators. Policies that undervalue covariance with price will lead to investments at the margin that have lower covariance with price. The statement in (26) implies that these policies will also shift investments at the margin so

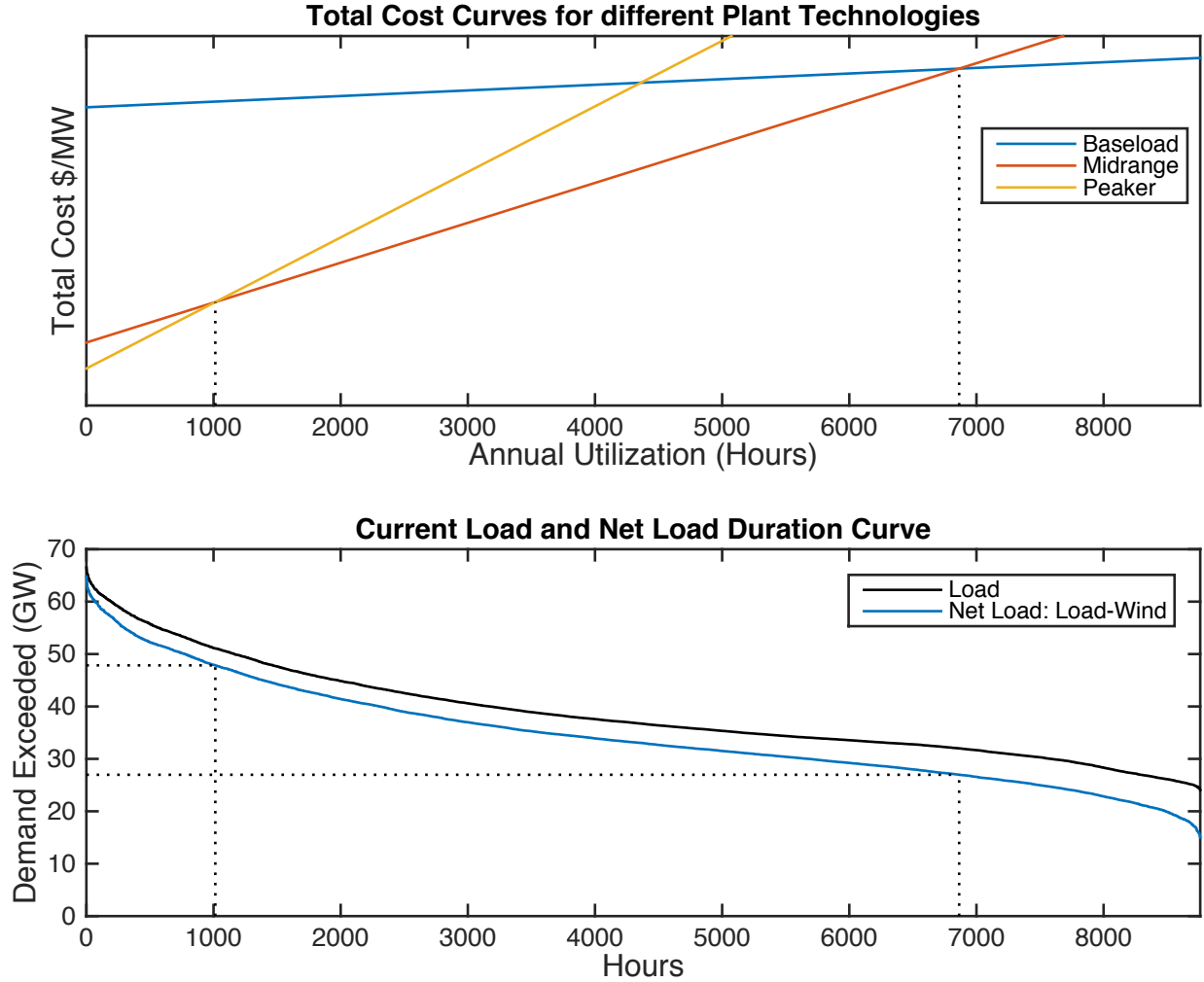


Figure 2: Cost Curves and Capacity Contributions in Theoretical Present-Day ERCOT Equilibrium

they have higher variance with the rest of the wind portfolio. Furthermore, increased variance of individuals with the remaining portfolio is equivalent to increased variance of the entire portfolio. Consider a system with N wind sites. Then $\text{Var}(\sum_{k \in N} f_k) = \sum_{k \in N} \text{Var}(f_k) + \sum_{k, j \in N, k \neq j} \text{Cov}(f_k, f_j) = \sum_{k \in N} \text{Var}(f_k) + \sum_{k \in N} \text{Cov}(f_k, S_{-k})$. Thus subsidies that reduce the marginal impact of price covariance on the investment decision bias investment decisions towards a system with higher portfolio variance.

High variance of portfolio wind generation outputs results in lower value of the available wind production and lower prices paid to generators, but it also increases reliability concerns. This can manifest in two ways. First, it increases the need for fast-ramping capacity, which could impose additional costs on the system or necessitate the creation of new ancillary service markets. Second, the reliability problem could increase resource adequacy concerns because the wind portfolio has incrementally lower "firm" (i.e. with high probability) availability as the standard deviation increases. A well-functioning energy-only market, such as the one described by Hogan [3] with an operating reserve demand curve, should help to counteract that and should provide incentives for efficient wind investment, in line with the frontier described in 10. However, policies like the PTC that affect the efficient frontier could increase externalities related to system reliability and increase tension regarding the inefficiencies of existing capacity mechanisms.

5 Impacts of Wind Generation on System Prices and Long-Run Market Equilibrium

The previous section showed that increased wind variance would exert downward pressure on electricity prices at precisely the times when production is likely to be high at individual generators. This section models that result to elucidate the effects of wind generation on market prices and long-run market equilibriums. This section will also show how the difference in correlation amongst wind investments can have an impact on the suppression of market prices.

This analysis focuses on a simplified market model with three types of traditional generators, a "baseload" plant that models a coal plant, a "midrange" plant that models a combined cycle plant, and a "peaker" plant that models a combustion turbine. The fixed and variable costs for the plants are estimated based on levelized cost of energy (LCOE) analysis from the EIA, except we assume a 50% increase in fuel costs for the natural gas plants. At current prices, natural gas plants dominate versus the 'baseload' plant, so this is intended to show the effects of wind on a market where there is more competition between new investment in competing generation technologies. The model is intended to provide a general analysis of the trade off between fixed and variable prices. The EIA parameter values are just used to ground the cost curves with some basis in reality; the specific values are not essential to our analysis.

Current market conditions and the load duration curve are based on data from ERCOT in 2014, with a peak demand of 66.5 GW. It is assumed that wind energy is always dispatched when available, with a marginal cost of 0, so it is considered as negative load. We find the load duration curve for the net load, which is the demand minus wind generation in any given hour.

We make that counter-factual assumption that the market was in long-run equilibrium in 2014, with the given mix of wind and traditional generation, in order to examine the effects of an expansion of wind. Generator are modeled as having a linear total cost curve, with the x-axis as hours of operation, with the y-intercept based on the total fixed costs and the slope based on the marginal costs of that particular generator, as shown in Figure 2. Clearly, in an efficient long-run equilibrium, the optimal mix of plants should be such that the plant type operating for t hours of the year should be the plant type that minimizes total fixed costs for that number of hours of operation t , i.e. if the total cost of a plant type j , that is operated for t hours in a year, is given by $C_j(t)$, than any plant operating for t hours must be of type $\arg \min_j \{C_j(t)\}$ in the theoretical equilibrium.

Figure 2 shows that the long-run equilibrium implies that each type of generator is operating in the range of hours in which that generator type has the lowest total cost. For example, 16.9 GW of peaker capacity is installed, operating up to 1014 hours, while any plant that operates more than 6864 hours is a baseload plant, in line with the long-run equilibrium that minimizes total cost, and 27 GW of baseload plants are installed.

Next, imagine that wind investment triples the annual production of wind energy, with no change in demand or in the array of available options for traditional generation. Consider two extreme cases, where the new wind is perfectly correlated to the existing resource, and where the new wind is independent of the existing wind resource. As argued in the previous sections, the system should expect higher portfolio variance amongst new investments under a policy that undervalues the effect of covariance with price, which is modeled in an extreme case here where new generation is perfectly correlated with existing generation.

5.1 Effect on System Prices

The bottom graph of Figure 4 displays the effect on the net-load duration curve for the correlated and uncorrelated wind investment cases. The correlated wind investment results in a steeper net-load duration curve, so the peak demand hours have higher demand versus the uncorrelated investment case, while the lowest demand hours have lower demand versus the uncorrelated investment case.

To calculate the short-run effect on system prices, we use the load duration curves in Figure 4, but apply the existing equilibrium resource mix to see which resource type sets the price in various hours, with the capacities for the existing resource mix shown in Figure 2. Figure 3 displays the results for the base-case and for highly correlated and uncorrelated wind expansion, the number of hours in a year that each generator type sets the price.

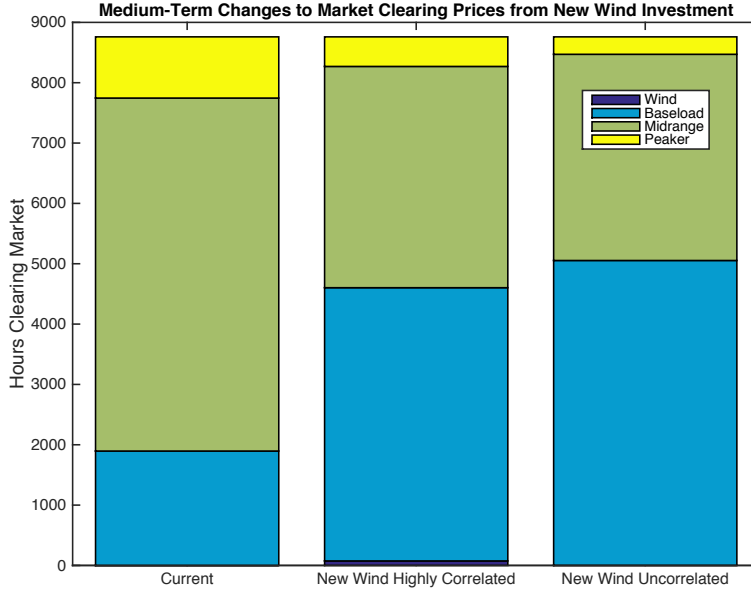


Figure 3: Hours in which different resources set clearing prices under equilibrium and two new investment cases, with no change in traditional resources

As expected, wind expansion serves to reduce the price of electricity, which is clear because resources with lower marginal cost (baseload) clear the market more frequently, while resources with higher marginal cost (peaker) clear the market less frequently. This helps validate the previous assumptions that wind serves to suppress market prices. The empirical estimates of correlation in our model also show that the more highly correlated wind output has lower covariance with price, as predicted by the model in Section 4. Using the market-clearing generators in Figure 3, and assuming the market clears at their marginal cost, $Corr(f_{hc}, \pi_{hc}) = -0.6056$ while $Corr(f_{uc}, \pi_{uc}) = -0.4073$ (and similarly for covariance), where “hc” and “uc” represent the wind production and corresponding prices in the highly correlated and uncorrelated investment cases. As expected, a higher correlation amongst the new wind investment leads to a more negative correlation of the output with the new prices in each period.

It is also interesting to compare the market prices in the case of highly correlated wind investment and uncorrelated wind investment, as seen in Figure 3. Notably, in the case of highly correlated wind investment we see less price suppression from the wind resource, so the same amount of wind capacity has less price benefits for consumers of electricity.

From this analysis, two important themes emerge. First, the analysis provides additional evidence to highlight the relationship between the covariance of price and wind availability and the total portfolio variance. If wind output is highly correlated in the investment portfolio, then each individual plant’s output is likely to be more negatively correlated with price, and the value of its energy will be lower. Therefore, as suggested, inefficient investment mechanisms, such as those introduced in the previous section, are likely to result in a wind portfolio mix that has an inefficiently high variance. Furthermore, the correlation amongst wind outputs affects price suppression. Correlated wind outputs weaken the price reduction effects of wind in the medium-term. Thus, inefficient investment mechanisms decrease the price benefits of new wind investment. While the inefficiency is apparent from a price perspective, it also has reliability impacts that may impart additional costs.

5.2 Effect on Long-Run Equilibrium

While wind energy places downward pressure on energy market prices in the short and medium-run, a more careful analysis is required to understand the effect of wind energy on the long-run equilibrium market prices. In particular, the long-run distribution of system prices in a theoretical market equilibrium should be based

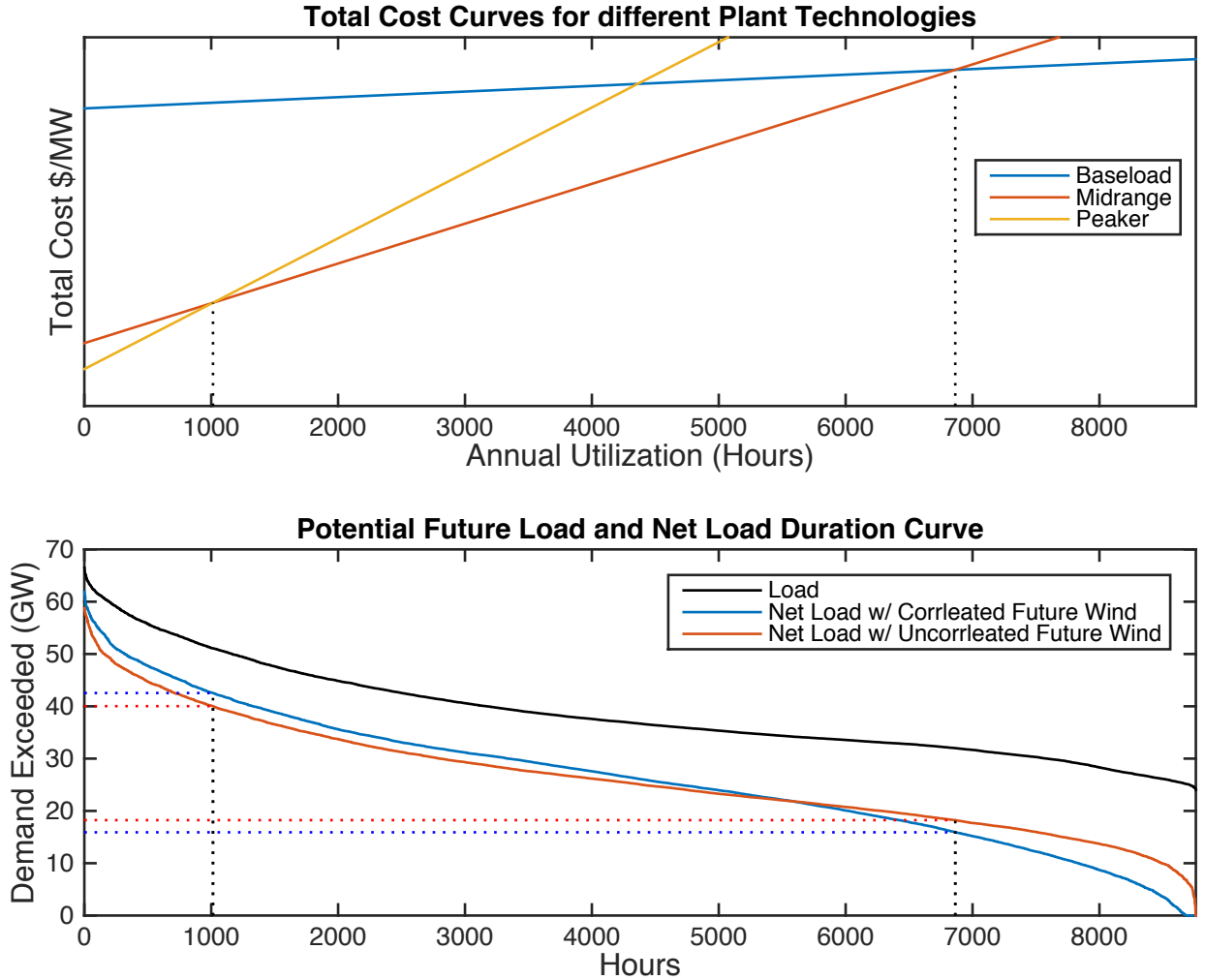


Figure 4: Potential future net load curves under different wind investments, and calculation example of future capacity of different resources under different wind investment scenarios

only on the total cost curves of the traditional generators with firm capacity [4] [13].

As explained by Sáenz et al., the implication of this is that wind-producers will drive prices down in the short-run, and it will become clear in the medium-run that there is an over investment in baseload plants compared to the new long-run efficient outcome. In time, however, investment decisions will actually shift capacity towards more peaker plants and should actually return prices towards the levels that existed in the absence of wind [13].

The reason for this is clear: in the long-run equilibrium, any plant operating for $t \in [0, 8760]$ hours should be the plant that minimizes the total cost curve at that particular level of operation. For instance, if the total cost of a plant type j is given by C_j , then the long-run equilibrium cost curve is given by $C(t) = \min_j \{C_j(t)\}$, and any plant operating for t hours must be of type $\arg \min_j \{C_j(t)\}$ in the theoretical equilibrium.

This leads to the interesting result that wind should not substantially affect prices in a long-run equilibrium, because the technology with the lowest cost for any range of t will run exactly that many hours in a year, over the very long-run when market entry and exit are taken into account. Therefore, Figure 4 can be used to analyze the potential capacity of different generation types under an expansion of wind in ERCOT, based on the two load duration curves for correlated and uncorrelated future wind resources. The results are shown in Figure 5.

As evident in Figure 5, the highly correlated equilibrium leads an increase in the capacity served by

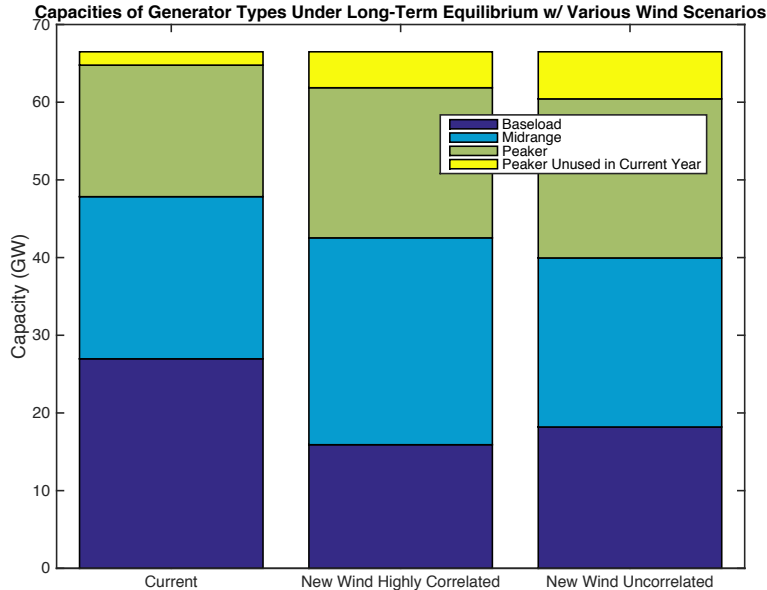


Figure 5: Long-run equilibrium capacity of each resource, including peaker resources that may be required for reliability but that are unused in the simulated year

midrange plants, but actually decreases the capacity served by both baseload and peaker plants. This is explained by the fact that in the correlated wind investment scenario, the slope of the load duration curve is generally steeper in the middle of the graph, and less steep at the ends, because correlated wind resources lead to more hours with a high or low level of demand. As a result, the midrange plants actually meet an increased portion of total capacity in equilibrium.

This result goes against conventional wisdom, which is that more highly correlated wind results in increased market appetite for peaker plants and less so for baseload plants. In both cases of significant wind investment the model suggests long-run suppression of base-load capacity, as expected. However, compared to the equilibrium in the uncorrelated case, more midrange capacity and less peaker capacity is present in the equilibrium for highly correlated wind investment.

In both cases of expanded wind investment, wind covers an increasing amount of demand in all hours. In the strictest interpretation of reliability, grid operators might find it necessary to have capacity available for all of that potential demand, in case no wind is available during hours of peak demand in a future year. The size of this capacity, technically necessary to cover demand in the absence of wind but unused in the current year, represented by the yellow bar in Figure 5. Alternatively, it provides a practical way of measuring the expected benefits wind provides as a capacity source.

As one might expect, in the uncorrelated case, the wind meets a greater level of capacity demand. However, it is difficult to compare the uncertainty in this value across different wind investment cases. Future research could use wind data across any given electricity system to estimate how variance in total portfolio output affects the tails of the distribution.

If operators accept that wind has a lower firm value as resource capacity than its contribution towards net demand in any given year, this suggests that there will be some traditional generator units demanded by the market or by regulation that actually do not operate at all in an average year. In theory, peak scarcity pricing could work the same way for these units as other peakers, except that scarcity rents would rise even higher to reflect the lower number of operating hours in expectation in a given year.

6 Conclusion

This paper examined optimal investment decisions in wind capacity, based on a simplification of analytical research on spot market pricing theory. It examined the investment frontier and considered trade offs between

marginally better capacity factors and marginally better covariance of output and prices.

The analysis shows that decisions along this investment frontier are biased fixed price subsidies like the production tax credit (PTC), resulting in wind investment that is marginally less likely to be available in periods of high prices and/or demand. Further results show that lower covariance or a wind site's output with price is equivalent to higher covariance with the remainder of system wind output. Therefore, subsidies like the PTC lead to investment decisions at the margin that inefficiently increase the total variance of the wind portfolio. The effects of portfolio variance on long-run market equilibriums were presented. Contrary to the typical assumption, more highly correlated wind investments actually support less peaker capacity in the long-run equilibrium versus an a portfolio of wind investments with less correlation in their outputs. Future work could examine other costs or externalities of high wind portfolio variance, or estimate the magnitude of the effects described here in a real electricity system.

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